The Potential Role of Combined Heat and Power Systems in Destroying Volatile Organic Compounds from Dried Distiller's Grain Solids Dryers in the Ethanol Industry

Introduction

The need to control volatile organic compounds (VOCs) from the dried distiller's grain solids (DDGS) dryers and the cost and energy consumption of thermal oxidizers (TO) present important issues for the ethanol industry. Combined heat and power (CHP) systems may offer alternative VOC destruction options for ethanol producers. A number of industry contacts have emphasized that a CHP system that also served as a VOC oxidizer would be a great benefit to the industry and enhance the acceptance of CHP within the ethanol industry.

The EPA CHP Partnership team has conducted a preliminary evaluation of the ability of CHP systems to serve as VOC oxidizers. A limited variety of options were researched in terms of technical status, relative cost and CO2 emissions. These options include gas turbine CHP, boiler/steam turbine CHP, and a steam turbine driven by steam generated by the thermal oxidizer. This paper summarizes the preliminary findings that the team has developed towards defining CHP systems that integrate VOC destruction.

A number of actions were taken to evaluate the integration of VOC destruction and CHP:

- Data was collected on the characteristics of exhaust gas from DDGS dryers;
- DDGS exhaust gas characteristics were supplied to selected gas turbine and heat recovery steam generator (HRSG) duct burner manufacturers to get assessments of the capability of their equipment to destroy VOCs in a CHP configuration;
- Preliminary cost and performance data was collected on thermal oxidizer systems currently being used by the ethanol industry;
- Various manufacturers and plant designers were contacted to identify specific CHP/VOC integration design issues that would require resolution;
- A "first cut" analysis was conducted of relative energy efficiency, emissions performance and economics of applicable CHP/VOC options compared with conventional non-CHP boiler and regenerative thermal oxidizer plant designs.

CHP VOC Destruction Options

Most dry mill ethanol plants are required to control VOC emissions present in the exhaust of DDGS dryers. Almost all ethanol plants are located in attainment areas and are subject to major source PSD permitting requirements if their potential to emit is 100 tons per year (tpy) or more of VOCs. Existing plants generally have adopted one of two options: install a regenerative thermal oxidizer (TO) that minimizes fuel use; or install a non-regenerative TO with a heat recovery steam generator (HRSG) that consumes more fuel, but replaces a portion of the plant's existing boiler output. Many new ethanol plants are designing to control VOCs enough to keep their emissions below the 100 tpy to avoid major source PSD permitting. New plants using conventional ethanol plant designs would most likely install the TO/HRSG option and reduce the size of the initial boiler installation. Depending on the uncontrolled VOC emission rate for a specific plant, the level of VOC destruction needed to keep VOC emissions below 100 tpy may be 95% or less. Integrating VOC destruction with CHP may enhance the value of CHP to the industry and accelerate market acceptance.

There are four potential alternative approaches for integrating CHP and VOC destruction in ethanol plants:

1. **VOC destruction directly in the gas turbine combustor:** This entails ingesting the exhaust from the DDGS dryer directly into the gas turbine combustor as a portion of the turbine inlet air flow. This is a potential option for some gas turbines (radial designs), but has not been evaluated in any detail or demonstrated. The extent of required upfront clean-up of the dryer exhaust stream is unknown, levels of achievable VOC destruction are not verified, and potential impact on turbine performance and life is uncertain. Because of these uncertainties, this approach is not considered a near-term option.

   Status: VOC destruction, design details and economics uncertain.
   Development Needs: Engineering analysis, combustion and turbine modeling, turbine testing and plant demonstration to verify performance and economics.

2. **VOC destruction in the gas turbine HRSG with a supplemental duct burner:** In this case the DDGS exhaust is ducted to the HRSG after the gas turbine, and the supplemental duct burner/HRSG serves as the TO, destroying VOCs and generating steam. This approach has been demonstrated in other applications. Unknowns for ethanol applications are the incremental costs to the HRSG and burner, impacts on NOx and other air emissions from the system, and impact on the power-to-steam balance of the CHP system and plant (auxiliary air is needed in the HRSG to ensure complete combustion, increasing the supplemental fuel use and steam output of the HRSG). The system may produce more steam than the plant requires but additional power could be generated from this excess steam).

   Status: VOC destruction achievable based on analysis by duct burner manufacturers; specific engineering for ethanol not completed and economics not determined.
   Development Needs: Engineering design and optimization, detailed economic analysis, and in-plant demonstration.

3. **VOC destruction in a high-pressure steam boiler (gas, coal or other fuels) CHP system:** In this case the DDGS exhaust is ducted to steam boiler(s) where the exhaust serves as a portion of the boiler combustion air. This approach is currently being designed for several new ethanol plants using fluidized bed coal boilers. This option requires using a steam heated DDGS dryer instead of the standard gas-fired dryer currently used by the industry in order to provide enough oxygen in the dryer exhaust to support combustion in the boiler.

Issues with this approach include potential impacts on dryer design and cost, impacts on boiler cost, the potential need for DDGS exhaust gas clean-up and/or drying, and the increased complexity of the system.

Status: VOC destruction achievable, detailed designs under development, economics not yet demonstrated.
Development Needs: Demonstration and economic verification of integrated boiler/VOC systems currently in planning stages; economic analysis to support use of high pressure boiler/steam turbine CHP approach instead of low pressure steam, non-CHP systems.

4. **Recover high pressure steam from a non-regenerative thermal oxidizer (TO) to generate power through a steam turbine before exhausting low pressure steam to the process:** In this case a high pressure HRSG is paired with the non-regenerative TO. This is a straightforward approach that depends on relative economics (additional fuel and costs in the TO/HRSG to generate high pressure steam, cost of the steam turbine generator, savings in purchased electricity). Although this option would be a simple retrofit option for existing plants installing a non-regenerative TO, it does not appear to be a standard offer from engineering/design firms.

   Status: VOC destruction achievable, economics site dependent.
   Development Needs: Detailed analysis to estimate costs and savings, demonstration to verify economics and emissions impacts.

Preliminary Comparison of CHP/VOC Integration Options

A "first cut" analysis of relative energy efficiency, emissions performance and economics was conducted of CHP/VOC integration approaches 2, 3, and 4 above compared with conventional non-CHP boiler plant designs. CHP/VOC integration approach 1, VOC destruction directly in the turbine combustor, was not included in the analysis due to technical uncertainties to the approach.

The analysis was based on a hypothetical 50 million gallons/year dry mill ethanol plant with an average power demand of 5.5 MW and a process steam demand of 150,000 pounds/hour (150 psia). Two base case plant designs were considered:

- Base Case 1 - Conventional (non-CHP) gas boiler, gas-fired DDGS dryer, and regenerative thermal oxidizer.

- Base Case 2 - Non-CHP fluidized-bed coal boiler with exhaust from a steam-heated DDGS dryer (plant steam demand increases to 200,000 lbs/hr) integrated into the boiler intake for VOC control.

Three CHP/VOC plant designs were evaluated:

- CHP/VOC Option A - Non-regenerative thermal oxidizer with high pressure HRSG/steam turbine generator, non-CHP gas boiler for remaining steam demand, and gas-fired DDGS dryer (compared to Base Case 1).

- CHP/VOC Option B - Gas Turbine CHP, supplementary-fired HRSG with gas-fired DDGS dryer exhaust integrated into duct burners for VOC destruction (compared to Base Case 1).

- CHP/VOC Option C - High pressure fluidized-bed coal boiler with steam turbine generator, with exhaust from steam-heated DDGS dryer integrated into the boiler intake for VOC destruction (compared to Base Case 2).

Results of the analysis are shown in Table 1. All three potential CHP/VOC integration options use less total energy and release less total air emissions than their respective base cases. Specific economic performance depends on prevailing fuel and electricity rates at particular sites, but relative economics for each option are presented in the table based on fuel and electricity assumptions that are reflective of current industry costs. A detailed assumptions and results spreadsheet is attached as an appendix to this paper.

Table 1 – Performance of CHP/VOC Integration Options

	Base Case 1 Gas Boiler w/o CHP, w/regen TO	CHP/VOC Option A Gas boiler and nonregen TO CHP	CHP/VOC Option B Gas Turbine CHP w/HRSG VOC	Base Case 2 Coal Boiler w/o CHP w/integral VOC	CHP/VOC Option C Coal Boiler CHP w/integral VOC
Plant Data					
Plant Capacity, Mmgal/yr	50	50	50	50	50
Electric Demand, MW	5.5	5.5	5.5	5.5	5.5
Steam Demand, lbs/hr	150,000	150,000	150,000	200,000	200,000
Boiler Steam, lbs/hr	*150,000*	*57,000*	*0*	*200,000*	*200,000*
Other Steam, lbs/hr	*0*	*93,000*	*150,000*	*NA*	*NA*
CHP Capacity, MW	0	3.0	5.2	0	4.0
Generated Electricity, MWh	0	26,280	45,552	0	35,040
Purchased Electricity, MWh	48,000	21,720	2,448	48,000	12,960
Annual Operating Hours	8,760	8,760	8,760	8,760	8,760
Energy Use					
Plant Fuel Use, MMBtu/yr	2,263,969	2,308,492	2,592,782	2,110,843	2,321,928
Central Station Fuel Use, MMBtu/yr	511,800	231,590	26,102	511,800	138,186
Total Fuel Use, MMBtu/yr	2,775,769	2,540,082	2,618,884	2,622,643	2,460,114
Emissions					
Carbon, ethanol plant, tons/yr	38,487	39,244	44,247	69,658	76,624
Carbon, purch electricity, tons/yr	12,778	5,782	652	12,778	3,450
Carbon, total, tons/yr	51,265	45,026	44,899	82,436	80,074
Carbon Savings, tons/yr	Base Case	6,239	6,366	Base Case	2,362
NOx, ethanol plant, tons/yr	77	74	100	106	116
NOx, purch electricity, tons/yr	98	44	5	98	27
NOx, total, tons/yr	175	118	105	204	143
NOx Savings, tons/yr	Base Case	57	70	Base Case	61
Economics					
Capital Costs, Installed $					
Boiler	$2,250,000	$1,500,000	$0	$20,000,000	$22,000,000
Thermal Oxidizer	$1,000,000	$1,725,000	$0	$0	$0
Steam Turbine Generator	$0	$2,400,000	$0	$0	$2,800,000
Gas Turbine/HRSG	$0	$0	$6,240,000	$0	$0
Total Capital Costs	$3,250,000	$5,625,000	$6,240,000	$20,000,000	$24,800,000
Operating Costs					
Electric Price, $/kWh	$0.07	$0.07	$0.07	$0.07	$0.07
Nat Gas Price, $/mmBtu	$6.50	$6.50	$6.50	NA	NA
Coal Price, $/mmBtu	NA	NA	NA	$2.50	$2.50
Annual Fuel Costs, $	$14,715,799	$15,005,198	$16,853,083	$5,277,108	$5,804,820
Annual Electric Costs, $	$3,360,000	$1,520,400	$171,360	$3,360,000	$907,200
Incremental O&M Costs, $	$0	$105,120	$250,536	$0	$140,160
Total Energy Operating Costs, $	$18,075,799	$16,630,718	$17,274,979	$8,637,108	$6,852,180
Payback, yrs	NA	1.6	3.7	NA	2.7

- Energy prices used in Table 1 for comparative economics are illustrative. Actual electric, natural gas and coal prices are region and site specific and can vary widely from the values used in the table
- Table 1 NOx emissions comparisons based on: 0.05 lbs/MMBtu for gas boilers and DDGS dryers; 0.1 lbs/MMBtu for coal boilers; 1.25 lbs/MWh for gas turbine; 0.08 lbs/MMBtu for HRSG duct burner, and 4.09 lbs/MWh for displaced electricity (EPA EGRID fossil average for 2002). Detailed assumptions in Appendix B.
- Table 1 Carbon equivalent emissions comparison based on 34 lbs Carbon/MMBtu for natural gas, 66 lbs/MMBtu for coal, and 534 lbs/MWhe for displaced electricity (EPA EGRID fossil average for 2002).
- Table 1 capital cost estimates are preliminary "budgetary" rules of thumb, based on typical natural gas packaged boilers, fluidized-bed coal boilers, and typical gas turbine CHP and steam turbine generator costs.

Conclusions

Gas Turbine HRSG CHP/VOC Integration - Gas turbine CHP is a proven option that can provide significant efficiency improvements and emissions reductions for existing plants using natural gas as the primary boiler fuel and for new plants planning to use natural gas. Verifying the technical feasibility and economic benefits of VOC destruction in a HRSG could further the adoption of gas turbine CHP with integrated HRSG/VOC destruction as a cost-effective energy strategy for ethanol facilities.

Next steps - The next step in confirming the benefits of the gas turbine HRSG VOC integration option would be a detailed analysis of the cost and performance of candidate turbine-duct burner systems for VOC destruction. Design optimization is required to minimize the need for auxiliary combustion air in the HRSG to better match steam output and plant needs. The impact of a steam heated DDGS dryer versus a conventional direct-fired gas dryer should be evaluated, including the effect on HRSG integration and overall steam balance. Since CHP systems are significant capital investments and require a long time to construct, candidate design concepts should be evaluated using a well established process design and simulation tool. The participation of equipment manufacturers would assist in the development of complete material and energy balances and equipment specifications, and accelerate commercial acceptance. Commercial demonstrations should be conducted once design concepts are verified using process simulation tools.

Thermal Oxidizer/HRSG CHP – Existing plants that have made the decision to install a thermal oxidizer could consider a non-regenerative TO with a high pressure HRSG for steam turbine power generation. Payback for this option should be relatively low based on preliminary estimates of incremental costs for the steam turbine generator and controls and for the higher pressure steam capability of the HRSG. Incorporating CHP would result in total energy efficiency improvements and reduced emissions.

Next Steps - Development of detailed economic analyses would help accelerate acceptance of the practice by both design firms and users.

Boiler/Steam Turbine CHP/VOC Integration - New plants planning to utilize coal or other low cost fuels and integrating VOC destruction in the boiler could consider CHP - increasing steam output pressure of the boiler and installing a steam turbine for power generation. Paybacks for this option should be relatively low based on preliminary estimates of incremental costs for the steam turbine generator and controls and for the higher pressure steam capability of the boilers. Incorporating CHP would result in total energy efficiency improvements and reduced emissions.

Next Steps - Development of detailed economic analyses, a review of design issues, and verification of performance through demonstration, would accelerate acceptance of the practice by design firms and users.

Gas Turbine Combustion VOC destruction - Direct ingestion of the dryer exhaust stream into a gas turbine combustor for VOC destruction remains a longer term option, requiring detailed engineering evaluation and combustor testing.

Several State Environmental Agencies have indicated interest in supporting the demonstration of CHP with integrated VOC destruction systems. Plants that are currently considering VOC destruction options are potential demonstration sites.

Appendix A

Supporting Data and Summary of Industry Discussions

1. Dryer Flue Gas Conditions

In preparation for contacting turbine and duct burner manufacturers about the capabilities of their equipment to destroy the VOC in DDGS flue gas, the team collected data on dryer flue gas conditions. The Minnesota Department of Environmental Quality (MDEQ) was able to provide stack test data for the flue gas from three DDGS dryers at two sites. These test data are presented as Sites 1 and 2 in Table 2. Site 1 is a 46 million gallon per year ethanol plant operating a rotary dryer and a ring dryer. The dryer flue gases are combined and sent to a thermal oxidizer operating at 1650 ^{o}F with 97% - 98% VOC destruction efficiency. Site 2 is a 20 million gallon per year ethanol plant using a rotary dryer followed by a thermal oxidizer operating at 1450 to 1500 ^{o}F and achieving 99.5% VOC destruction. These test data contain a very complete set of flue gas characteristics, except they do not speciate the VOC component of the flue gas. Because some VOC species are difficult to destroy, the team also researched dryer VOC speciation data. From another study of VOC species in DDGS dryer flue gas conducted for EPA/OAQPS, the team obtained typical concentrations for the VOC species in the DDGS flue gas. These results are presented in Table 2 under sites 3 and 4.

The team also inquired about the physical characteristics of the particulate matter (PM) and the PM controls that were being applied between the dryer and the thermal oxidizers. MDEQ staff noted that many facilities employ cyclones or centrifugal collectors to remove larger particulates. To-date, they had not seen any advanced control such as fabric filters or electrostatic precipitators (ESPs). Minnesota is also encouraging the control of DDGS cooler vents. Ethanol plants may cool the DDGS out of the dryer to avoid clumping of the DDGS when it is transported by railcar. If the DDGS is loaded hot, it can clump together in the transport container, making it difficult to remove. MDEQ staff noted, however, that some ethanol plants have observed problems in controlling the DDGS cooler vents as the carry-over can gum up in the thermal oxidizer, causing fires in some cases. The use of fluid bed DDGS coolers seems to minimize this problem.

Table 2. Properties of Distiller's Dried Grain Solids Dryer Exhaust

	Site 1	Site 2	Site 3	Site 4
Ethanol Plant Production (M gal/yr)	46	20	10	20
Exhaust flow rate (dscfm)	25,250	15,500		
Temperature (^oF)	233	220		
Moisture (%)	49	45		
Carbon dioxide (wet %)	5			
Oxygen (dry %)	13			
Particulate matter (lb/hr –exiting the RTO)	5.8	1.7		
Volatile organic compounds (ppm C, wet)	1614	760		
Volatile organic compounds (lb C/hr)	152	40.1	44.3	59.1
Total Hydrocarbons (ppm C_3H_8, wet)		253		
Ethanol (% of VOC)			7	2
Acetic Acid (% of VOC)			40	41
Formaldehyde (% of VOC)			1.2	1.9
Furfuraldehyde (% of VOC)			0	0.6
Acetaldehyde (% of VOC)			2.3	4.6
Acrolein (% of VOC)			0.1	0.5
Methanol (% of VOC)			0.4	0.2

2. Gas Turbine CHP/VOC Integration Issues - Feedback from Gas Turbine and Duct Burner Manufacturers

The team sent DDGS dryer flue gas composition data to four turbine manufacturers/packagers and two duct burner manufacturers for their analysis of the potential to destroy VOC in CHP systems using their equipment:

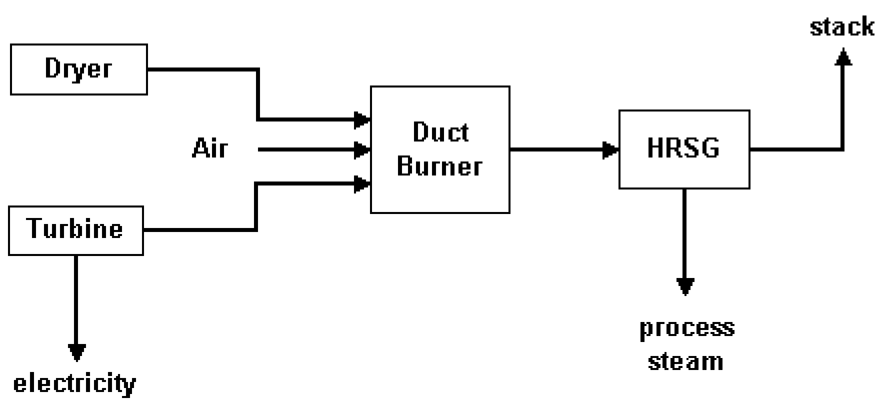
- Duct Burner Manufacturer A considered the dryer exhaust too wet to support combustion in a duct burner unless the water is removed or dry combustion air is added. However, once one of these conditions is met, they were confident that duct burners would be able to destroy 95% to 98% of the VOC species in the dryer flue gas.

- Duct Burner Manufacturer B estimated that the temperature required to burn the VOC might be 1500 to 1600 ^oF. They projected that stable combustion of the wet flue gas could be achieved in the duct burner by feeding the burners 63% stoichiometric ambient air and mixing the burner exhaust with the dryer flue gas.

- Gas Turbine Manufacturer A has a radial turbine that has shown 95% to 99+% destruction of VOC species that are analogous or even more difficult to burn than the VOC species in the DDGS dryer flue gas. However, it is unclear whether the manufacturer has dealt with the high levels of moisture and particulates found in the DDGS dryer exhaust. To use the dryer flue gas as turbine air, the flue gas must be cooled to less than 110 ^oF and will require filtering with a large scroll filter. The turbine efficiency is significantly reduced as the temperature of the inlet air increases. For the 15,000 dscfm flue gas flow of the smaller dryer, the manufacturer recommended using a 7 MW turbine.

- Gas Turbine Manufacturer B's axial turbine is not an effective VOC destruction device because a large portion of the incoming air (estimated up to 40%) is used to cool the turbine blades and thus bypasses the combustion zone. If the dryer flue gas is used as the combustion air for this turbine, much of the VOC will not be exposed to sufficient heat to guarantee its destruction. The manufacturer also cited concerns with the PM and other contaminants in the dryer exhaust fouling the turbine components. The manufacturer recommended evaluating VOC destruction by combining the hot turbine exhaust with the dryer flue gas and sending the mixture to a duct burner.

The team did not receive responses from two of the gas turbine manufacturers contacted, but the initial analysis provided by the other manufacturers indicates that the destruction of the VOC would be most likely accomplished with HRSG duct burners in a CHP system similar to the one shown below. By destroying the VOC with a duct burner, the need to remove moisture, heat, or contaminants from the dryer exhaust is avoided (which would be required if it were used as the feed to a turbine). The turbine exhaust helps preheat the dryer flue gas and provides oxygen for the duct burners. The design also provides for VOC destruction even when the turbine is out of service or not needed. Finally, valuable heat from the turbine exhaust, the dryer flue gas, and the duct burner is recovered in a heat recovery steam generator (HRSG).



Cooling the dryer flue gas as suggested by the representative from Duct Burner A creates a significant cooling load on the system and reduces the benefits of recovering the waste heat in the flue gas. However, if process steam from the plant can be used to condense significant dryer moisture, the fuel load in the duct burner would be greatly reduced. Providing 63% stoichiometric ambient air to the duct burner (as suggested by Duct Burner Manufacturer B) produces a significant heat sink that requires a large volume of natural gas and results in the production of 25 to 50% more steam than required by the ethanol process. The dryer flue gas PM and high moisture content are also potential problems for integration into the HRSG.

The conclusion from these preliminary discussions is that integrating VOC destruction with a gas turbine HRSG looks promising as a way to replace separate TOs, but its economic success will depend on finding ways to optimize energy use in the system.

3. Characterization of Thermal Oxidizers

The team contacted two thermal oxidizer (TO) companies to obtain information on TO cost and performance. This information was used to compare other CHP/VOC options to approaches using TOs for VOC control. TO Manufacturer A is a firm that had only recently entered the ethanol market and could therefore provide only limited data on TO designs for ethanol applications. TO Manufacturer B has installed numerous TOs on ethanol plants and was able to provide detailed design specifications and costs for three TO designs commonly used at a 45-50 million gallon per year ethanol plant (Table 3).

Table 3 - Estimated Thermal Oxidizers System Parameters:

	1	2	3
	Conventional T.O. w/ 50% heat recuperation followed by HRSG	Conventional T.O. w/ No heat exchange, but followed by HRSG	Regenerative T.O.
Equipment in the system >>>	T. Oxidizer Heat Exchanger HRSG	T. Oxidizer HRSG	T. Oxidizer
Dryer Exhaust flow (scfm)	44,132	44,132	44,132
Dryer Exhaust humidity (%)	50	50	50
Dryer Exhaust temp (^oF)	240	240	240
N. Gas flow (scfm)	1,022	2,035	31.4
Combustion air (scfm)	11,839	23,560	330
T.O. combustion temp. (^oF)	1550	1550	1600
T.O. Exhaust temp. (^oF)	1,087	1550	320
T.O. Exhaust flow (scfm)	57,216	70,146	44,518
T.O. Exhaust flow (Btu/hr)	72,523,394	133,249,143	13,292,031
T.O. Exhaust NOx (lb/hr as NO_2)	8.1	10.7	4.7
T.O. Exhaust CO (lb/hr)	10.6	14.0	7.2
HRSG steam flow (lb/hr)	43,850	92,590	0
HRSG steam temp (^oF)*	700	700	700
HRSG steam pressure (psig)*	700	700	700
Capital Cost of T.O. ($)	700,000	750,000	850,000
Capital Cost of recuperator ($)	300,000	none	none
Capital Cost of HRSG ($)	650,000	800,000	none
Total Cost- capital ($)+	1,650,000	1,550,000	850,000
Total Cost- installation ($)+	200,000	175,000	150,000
Total Cost- Operation and Maint.			
Fuel (10^6 BTUH)	61.34	122.07	1.88
Electrical (kWh)	310	350	225
Annual Maintenance Hours	400	350	300
Annual Operator Hours	500	500	500

* Steam conditions - 700 psig w/ superheat (i.e. 700 ^oF)
\+ Preliminary “budgetary” quotes

Appendix B – CHP/VOC Performance Comparison

	Base Case 1	CHP/VOC Option A	CHP/VOC Option B	Base Case 2	CHP/VOC Option C
	Gas Boiler wo/CHP	Gas boiler and TO CHP	Gas Turbine CHP	Coal Boiler wo/CHP w/integral VOC	Coal Boiler CHP w/integral VOC
Plant Data					
Plant Capacity, Mmgal/yr	50	50	50	50	50
Operating Hours	8760	8760	8760	8760	8760
Electric Use, kWh/gal	0.96	0.96	0.96	0.96	0.96
Electric Use, MWh/yr	48,000	48,000	48,000	48,000	48,000
Electric Demand, MW	5.5	5.5	5.5	5.5	5.5
Steam Use, lbs/hr	150,000	150,000	150,000	200,000	200,000
Steam Use, lbs/yr	1,314,000,000	1,314,000,000	1,314,000,000	1,752,000,000	1,752,000,000
Coal Costs, $/MMBtu	$2.50	$2.50	$2.50	$2.50	$2.50
Nat Gas Costs, $/MMBtu	$6.50	$6.50	$6.50	$6.50	$6.50
Electric Costs, $/kWh	$0.07	$0.07	$0.07	$0.07	$0.07
Boiler Fuel, MMBtu/yr	1,642,500	628,640	0	2,110,843	2,321,928
Steam Output, lb/yr	1,314,000,000	502,911,600	-200,280,000	1,752,000,000	1,752,000,000
Steam Output, lb/hr	150,000	57,410	-22,863	200,000	200,000
Drier Fuel, MMBtu/yr	605,000	605,000	605,000	0	0
Oxidizer Type	Regenerative	Conventional w/HRSG	NA	NA	NA
Thermal Oxidizer Fuel, MMBtu/yr	16,469	1,074,852	0	0	0
TO Steam Output, lb/yr	0	811,088,400	0	0	0
TO Steam Output, lb/hr	0	92,590	0	0	0
GT CHP Electric Efficiency, %	0	0.0	26.9	0.0	0.0
Gas Turbine Fuel Input, MMBtu/yr	0	0.0	577,782	0	0
HRSG Fuel Input, MMBtu/yr	0	0.0	1,410,000	0	0
GT CHP Steam Output, lb/hr	0	0.0	172,863	0	0
GT CHP Steam Output, lb/yr	0	0.0	1,514,280,000	0	0
			(capacity to produce excess steam over plant		
CHP Capacity, MW	0	3.0	5.2	0.0	4.0
Total Power Generated, MWh/yr	0	26,280	45,552	0	35,040
Purchased Power, MWh/yr	48,000	21,720	2,448	48,000	12,960
Total Plant Fuel Use, MMBtu/yr	2,263,969	2,308,492	2,592,782	2,110,843	2,321,928
Total Central Station Fuel Use, Mbtu/yr	511,800	231,590	26,102	511,800	138,186
Total Fuel Use, MMBtu/yr	2,775,769	2,540,081	2,618,884	2,622,643	2,460,114
Incremental O&M costs, $/kWh	0	0.004	0.0055	0	0.004
Capital Costs, Installed					
Boiler, $	$2,250,000	$1,500,000	$0	$20,000,000	$22,000,000
Thermal Oxidizer, $	$1,000,000	$1,725,000	$0	$0	$0
Steam Turbine Generator, &	$0	$2,400,000	$0	$0	$2,800,000
Gas Turbine CHP System, $	$0	$0	$6,240,000	$0	$0
Total Capital Costs, $	$3,250,000	$5,625,000	$6,240,000	$20,000,000	$24,800,000
Annual Fuel Costs, $	$14,715,797	$15,005,195	$16,853,085	$5,277,108	$5,804,819
Annual Electric Costs, $	$3,360,000	$1,520,400	$171,360	$3,360,000	$907,200
Incremental O&M Costs, &	$0	$105,120	$250,536	$0	$140,160
Total Annual Energy Costs, $	$18,075,797	$16,630,715	$17,274,981	$8,637,108	$6,852,179
Payback, yrs	NA	1.6	3.7	NA	2.7
		(Payback compared to Base Case 1)	(Payback compared to Base Case 1)		(Payback compared to Base Case 2)
Emissions					
Carbon, ethanol plant, tons/yr	38,487	39,244	44,077	69,658	76,624
Carbon, purch electricity, tons/yr	12,778	5,782	652	12,778	3,450
Carbon, Total, tons/yr	51,265	45,026	44,729	82,435	80,074
NOx, ethanol plant, tons/yr	77	74	100	106	116
NOx, purch electricity, tons/yr	98	44	5	98	27
NOx, Total, tons/yr	175	118	105	204	143

Assumptions

Assumptions		
Plant Steam Load		
Gas systems	150,000 lb/hr	EEA estimate - high end of expected range for 50 Mmgal/yr plant
Coal systems	200,000 lb/hr	EEA estimate - high end of expected range for 50 Mmgal/yr plant and 50,000 lb/hr for DDGS drier
Gas Boiler Efficiency	80%	EEA estimate
Coal Boiler Efficiency	83%	EEA estimate
Gas Boiler Costs	15 $/lb	EEA estimate for 150,000 lb/hr boiler
	25 $/lb	EEA estimate for 60,000 lb/hr boiler
Coal Boiler Costs	100 $/lb	EEA estimate for high pressure 200,000 lb/hr stoker boiler (600psi)
	110 $/lb	EEA estimate for low pressure 200,000 lb/hr stoker boiler (150 pis)
Thermal Oxidizer Costs		
Regenerative	$1,000,000	ERG data
Non-regen w/HRSG	$1,725,000	ERG data
Steam Turbine Costs	$800/kW	EEA estimate - 3 MW
	$700/kW	EEA estimate - 4 MW
Gas Turbine Efficiency	26.9% HHV	Solar Turbines data
Gas Turbine Costs	$1200/kW	EEA estimates - includes oversize HRSG
HRSG fuel input	1,420,000 MMBtu/yr	Coen/ERG estimate
HRSG steam output	28,000 lb/hr	Solar Turbines data from unfired HRSG
	145,890 lb/hr	90% of HRSG fuel input
Carbon Equivalent emissions		
Gas boiler	34 lbs/MMBtu	
Gas drier	34 lbs/MMBtu	
Gas TO	34 lbs/MMBtu	
Gas Turbine	34 lbs/MMBtu	
Coal Boiler	66 lbs/MMBtu	
Displaced grid power	534 lbs/MWhe	EGRID (fossil average)
NOx emissions		
Gas Boiler	0.05 lb/MMBtu input	
Dryer	0.05 lb/MMBtu input	
Regen TO	2.5 lb/MMBtu inout	ERG data
Non-regen TO	0.08 lb/MMBtu input	ERG data
Gas Turbine	1.25 lb/MWhe	EEA data (25 ppm)
HRSG burner	0.08 lb/MMBtu input	Coen Burner data
Coal boiler	0.1 lb/MMBtu input	
Displaced Grid power	4.09 lbs/MWhe	EGRID (fossil average)